BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NOS. 2019-185-E and 2019-186-E – ORDER NO. 2019-881(A)

JANUARY 2, 2020

In the Matter of: Docket No. 2019-185-E – South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A) and Docket No. 2019-186-E – South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	)	AMENDED ORDER APPROVING DUKE ENERGY CAROLINAS, LLC'S AND DUKE ENERGY PROGRESS LLC'S STANDARD OFFER TARIFFS, AVOIDED COST METHODOLOGIES, FORM CONTRACT POWER PURCHASE AGREEMENTS, AND COMMITMENT TO SELL FORMS

Duke Witness Snider testified that DEC's projection of its first avoidable capacity need occurs in 2026, while DEP's first avoidable capacity need occurs in 2020, consistent with the Companies' 2019 IRP Update filings. He testified that accounting for the timing of needed capacity accurately values the capacity being delivered by the QF, consistent with PURPA's intent for the utility to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. (Tr. Vol. 1, p. 58.14-17.) Last, he explained that under the levelized Schedule PP rate design, the avoided capacity payment is levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost period. In conclusion, Witness Snider testified that the Companies' recognition of DEC's and DEP's need for capacity in the avoided capacity cost calculation is fair to both the Companies' customers and the QF. (Tr. Vol. 1, p. 17-18.)

ORS Witness Horii supported the method used by the Companies to calculate avoided capacity costs and stated that the method was one of the generally accepted methods for calculating PURPA avoided capacity costs used throughout the United States. (Tr. Vol. 2, p. 525.11.) He then testified that the lower avoided capacity rates calculated for DEC as compared to DEP were justified. In support of his position, Mr. Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent. In reviewing the Companies' load and resource balance

table that DEC provided to ORS as the basis for its capacity need determination, ORS Witness Horii found that the increases of generation capacity via capacity increases or uprates in 2021 through 2024 did not require DEC to recognize avoided capacity costs in those years. (Tr. Vol. 2, p. 525.11-12.) He also agreed that although DEC's load and resource balance table identified the addition of the Lincoln combustion turbine ("CT") in 2025, DEC appropriately identified 2026 as the first year of avoided capacity cost, because the Lincoln CT has already been approved and commenced construction. Therefore, Mr. Horii explained that moving the first year of avoided capacity costs to 2025 instead of 2026 would incorrectly increase the avoided capacity payments to QFs, and recommended the Commission approve the Companies' first year of capacity needs as identified in DEC's and DEP's 2019 IRP Updates and used in calculating the Companies' avoided cost rates. (*Id.*)

In response to Duke's avoided capacity cost calculation and identified first year of need, SCSBA Witness Burgess argued that Duke's proposal was biased against QFs and underestimated capacity value in two ways. First, he argued that for DEC, Duke inappropriately assumed that each QF would provide zero capacity value from 2020 through 2026. Although he admitted that Duke's load and resource forecast do not project an internal resource need until 2026, he stated that Duke has the option to sell its excess capacity in the wholesale capacity markets and to receive commensurate compensation for doing so. (Tr. Vol. 1, p. 382.62.) He argued that the addition of QF capacity would further increase Duke's capacity position, allowing for greater off-system sales. He therefore recommended that the QF capacity provided to DEC between 2020

and 2026 be traded by DEC either bilaterally or into PJM's Reliability Pricing Model capacity market, and subsequently credited to Duke's customers, despite admitting that this capacity "may not be necessary to cover any internal capacity deficiencies." (Tr. Vol. 1, p. 382.62-65.)

Second, he argued that Duke incorrectly assumes that each QF provides zero capacity value after 2029. In support of his argument, he argued that new generation sources, such as gas peakers, have a project life of 30 years or more, and that the benefit to ratepayers of avoided capacity from QFs may extend well beyond the life of the proposed 10-year contract period. He argued that Duke's proposal limits the capacity component of QF contracts to 10 years, even though solar PV resources have a project lifetime of 20 years or more. He therefore concluded that there is "significant likelihood" that the capacity from these projects could be re-contracted at a later date. (Tr. Vol. 1, p. 384.65.) He further argued that since there would be no fuel costs, transport costs, and minimal O&M costs, the cost to re-contract these QFs would likely be very low compared to other options, providing a "meaningful option value." However, he concluded by stating that he did not recommend adjusting Duke's avoided cost methodology to reflect this option value at this time. (Tr. Vol. 1, p. 384.66.)

In response to SCSBA's first critique of the Companies' identified first year of need, Duke Witness Snider explained that from a legal perspective, utilities are not obligated to pay QFs for capacity that exceeds system needs, such as for resale in a capacity market under PURPA. In support of his contention, he stated that FERC has long held that "an avoided cost rate need not include capacity unless the QF purchase will

permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) Witness Snider further explained that FERC has also expressly stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* Further, he stated that FERC has more recently reiterated that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.53-55 (citing *Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014)).)

In response to SCSBA Witness Burgess's second critique, Witness Snider explained that it is prudent resource planning not to rely upon assumed future third-party owned capacity in years where no contract or other legally enforceable commitment guaranteeing delivery exists. He explained that QF owners have unfettered rights to make a business decision at the time their current PPA expires whether or not to enter into a new PURPA contract with the Companies or otherwise use (or not use) their facility in any lawful manner as they so desire. He explained that the Companies and their customers have no guarantee that the contracted facility will be physically capable of providing energy and capacity beyond the contract period for a variety of reasons. He stated that Duke's current and consistent position across numerous biennial IRP planning cycles has been to treat all wholesale purchase contracts the same and to recognize that a QF's legally enforceable commitment to provide energy and capacity extends only for the

duration of its PPA. Further, he testified that Duke's position was fully consistent with FERC's implementing regulations, and that to presume a QF had made a commitment to deliver power to utility after its initial contract term ends would be inconsistent with PURPA. Witness Snider concluded by contending that SCSBA Witness Burgess' proposal is intended to advantage existing QFs over new QFs or other capacity resources, and is therefore discriminatory towards other traditional and non-traditional utility resources, in violation of PURPA's nondiscrimination principle. (Tr. Vol. 2, p. 630.56.)

On surrebuttal, SCSBA Witness Burgess did not refute Duke Witness Snider's claim that PURPA does not require utilities to pay QFs for capacity when there is no capacity need. Instead, Mr. Burgess questioned whether DEC's 2019 IRP reflected DEC's most current planning needs and requirements, arguing that it does not reflect DEC's planned accelerated retirements of five coal plants announced in DEC's September 30, 2019 North Carolina general rate case application after the 2019 IRP Updates were filed. (Tr. Vol. 2, p. 787.7.)

On cross-examination, Duke Witness Snider addressed the fact that DEC had recently announced the accelerated retirement of five coal plants after the 2019 IRP Updates were filed. He explained first, in terms of resource planning, a utility must make a determination or, "snap a chalk line," at a certain point in time and use the most up-to-date inputs and assumptions available at that point in time in developing its integrated resource plan. Second, he explained that the planned accelerated retirement of the coal plants referenced by SCSBA Witness Burgess were subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire

the units, as further evidence as to why those retirements were not included in the Companies' 2019 IRP Updates. Mr. Snider specifically explained that Duke has sought authorization to adjust the depreciable lives of these plants in DEC's now-pending North Carolina general rate case and, assuming the shorter depreciable lives are approved, that DEC would reflect this change in its 2020 IRP. (Tr. Vol. 1, p. 156-157) Last, he explained that although there was a possibility that these accelerated retirements could accelerate DEC's first year of need to 2025, and therefore increase the avoided capacity rate, recognizing the accelerated retirements of these older coal units would also impact DEC's marginal cost of energy thereby having the likely overall effect of lowering DEC's overall avoided cost rates. This result would be due to the acceleration of more cost-effective and efficient generation replacing the units, which result he contended would be adverse to SCSBA's interests. (Tr. Vol. 1, p. 163-164)

During SCSBA's examination of ORS Witness Horii at the hearing, Mr. Horii testified that he was unsure solar QFs could even meet the capacity need that would arise as a result of the five coal units being retired. He explained that according to his experience, "if you retire a unit, you need to basically sort of put in a large () replacement capacity project. And, in that case, there may be no sort of avoided cost savings because you're not going to be avoiding or deferring that next capacity project because you're putting it in there to replace the massive amount of capacity that you've lost through the retirement." (Tr. Vol. 2, p. 550.) ORS Witness Horii further agreed that the retirement of these coal units could lower the Companies' proposed avoided energy rate. Last, ORS Witness Horii agreed with Duke Witness Snider's statement that it is a reasonable

approach for a utility to select a specific point in time or to "snap a chalk line" in determining its resource plan and for purposes of calculating avoided cost rates. (Tr. Vol. 2, p. 550-551.)

Commission Determination

The Commission finds that DEC and DEP have appropriately identified their first avoidable capacity needs, as presented in their 2019 IRP Updates. ORS's expert Witness Horii testified that the Companies' use of the recently filed 2019 IRPs was appropriate, reasonable, and transparent, and the Commission finds merit in his testimony. Moreover, in regard to DEC's recently announced plans to accelerate retirement of certain coal units, the Commission finds that for purposes of this proceeding, it is reasonable not to consider those retirements in determining the DEC's first year of capacity for several reasons. As evidenced by Duke Witness Snider, it is necessary for the utilities to "snap a line in chalk" at some point in time for purposes of resource planning and calculating the Companies' avoided cost rates. ORS's expert Witness Horii agrees, and testified that this is a reasonable approach. Moreover, as also testified to by Duke Witness Snider, these five coal units have yet to receive the necessary regulatory approvals to be included in DEC's IRP as "committed" to these earlier retirement dates.

SCSBA's argument in support of including the prospective earlier retirement of the five coal units in DEC's calculation of avoided capacity costs was based upon the premise that including these retirements would accelerate the Companies' first year of capacity need, thereby increasing the avoided capacity rates approved in this proceeding to be paid to QF. However, Duke Witness Snider testified that consideration of the

accelerated retirement of these five coal plants would not only affect the Companies' avoided capacity rate, but also the system production cost of energy used to quantify the avoided energy rate. He explained that most likely, the aggregate effect of accounting for these accelerated coal unit retirements would be an overall decrease in the Companies' avoided cost rates, based on the likelihood that retiring older coal units would drive down the avoided energy rate more so than any increase in avoided capacity. ORS's expert Witness Horii agreed that Duke Witness Snider's contention was plausible, and SCSBA provided no evidence suggesting otherwise.

The Commission also recognizes and appreciates Power Advisory's recommendation that DEC be required to adjust forward its first year of capacity need to 2025 to reflect the likelihood that these accelerated coal unit retirements become part of the DEC's resource plans. *Power Advisory Report*, p. 21. However, as discussed above, the Commission finds that it is appropriate and necessary to "snap a chalk line" in developing inputs and assumptions for calculating avoided cost rates, that the loss in avoided energy payments may more than offset the gain in avoided capacity payments to QFs by recognizing the accelerated unit retirement date assumptions, that the acceleration in unit retirement dates is subject to future regulatory determinations prior to DEC actually committing in an integrated resource plan to retire the units, and that if shorter depreciable lives are approved, that DEC will appropriately reflect this change in its 2020 IRP.

Based upon all of the evidence on this issue, the Commission finds and concludes that DEC's identified first capacity need in 2026 and DEP's identified first capacity need

in 2020 are reasonable and appropriate for purposes of calculating avoided costs in this proceeding.

In regard to SCSBA's proposal to require the Companies to assume excess QF capacity can be sold into a wholesale capacity market prior to DEC's first year of capacity need in 2026, the Commission finds and concludes that such a requirement would be inconsistent with PURPA and contrary to FERC precedent. As cited to by Duke Witness Snider, FERC has held that "an avoided cost rate need not include capacity unless the QF purchase will permit the purchasing utility to avoid building or buying future capacity…(the purchase) obligation does not require a utility to pay for capacity that it does not need." (Tr. Vol. 2, p. 630.54 (citing *City of Ketchikan*, 94 FERC ¶ 61,293 (2001) (citing *Order No. 69*, at P 30,865)).) FERC has also stated that "there is no obligation under PURPA for a utility to pay for capacity that would displace its existing capacity arrangements," as neither PURPA nor FERC's regulations require utilities to pay for the QF's capacity irrespective of the need for the capacity." *Id.* FERC also reiterated in the *Hydronamics* decision cited by Duke Witness Snider that "when the demand for capacity is zero, the cost for capacity may also be zero." (Tr. Vol. 2, p. 630.54 *citing Hydrodynamics, Inc.,* 146 FERC ¶ 61, 193, at ¶ 35 (2014).) PURPA therefore does not force a utility and its customers to pay for capacity that it otherwise does not need to serve customers. SCSBA Witness Burgess testified in his surrebuttal testimony that "he [does not] disagree with this position. (Tr. Vol. 2, p. 787.20.) The Power Advisory Report also generally accepts Duke's position on this issue. *Power Advisory Report*, p. 21. Therefore, the Commission agrees with Duke and the ORS that